STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of Delmarva	**)**	
Power and Light Company for an	**)**	**Case No. 9192**
Increase in Its Retail Rates for the	**)**	
Distribution of Electric Energy	**)**	

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

THE OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

AUGUST 24, 2009

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I. Introduction and Summary

Q: Please state your name, occupation, and business address.

A: I am Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional education and experience.

A: I have worked as a consultant to the electric-power industry since 1981. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the last twenty-eight years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit JFW-1.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Office of People's Counsel.

Q: What is the purpose of your testimony?

A: On May 6, 2009, Delmarva Power and Light Company ("Delmarva"; "the Company") filed an application for an increase in its distribution rates, along with supporting testimony. This testimony addresses three aspects of the Company's filing: (1) the proposed allocation to the residential class of the requested revenue increase; (2) the Customer Class Cost Of Service Study ("COSS") that forms the basis for the proposed revenue allocation; and (3) the proposed residential rate design. These three elements are supported in the pre-filed testimony by Company witnesses Joseph F. Janocha and Elliot P. Tanos.

People's Counsel is also sponsoring testimony by Mr. David Effron regarding revenue requirements and Mr. Charles King regarding rate of return.

Q: Please summarize your conclusions and recommendations.

A: The Company's proposal for allocating the requested revenue increase to customer classes, in combination with its proposal to dramatically increase the residential customer charge, unduly and unreasonably burdens consumers, particularly low-usage customers. In this time of economic distress, the Company should be minimizing residential rate increases to the greatest extent feasible. Instead, the Company's proposal would allocate to residential ratepayers more of the requested revenue increase than is necessary to achieve the requested rate of return. The Company's proposal then further burdens smaller consumers by proposing to shift costs from energy charges to the customer charge.

I recommend the following actions to reduce the harm to consumers:

- The Commission should reject the Company's proposed approach for allocating to the residential class any increase in revenues that is ultimately approved by the Commission. Instead, the Company should be allowed to allocate only as much of the approved revenue increase required to achieve the authorized rate of return.
- The Company's proposal to increase the residential customer charge by 25% should be rejected. Instead, the customer charge should be increased

in proportion to the overall revenue increase allocated to the residential class.

- The Company's proposed method for reducing the declining-block structure in winter rates should be modified. While there is merit to the concept of reducing the difference between initial and trailing blocks, the proposed approach unreasonably reduces the summer-winter differential in energy charges for large residential customers. Instead, the revenue increase remaining after the customer charge is adjusted as recommended above should be applied in a manner that both reduces the declining-block structure in the winter and provides for a summer-winter differential.

Q: Have you prepared an exhibit that illustrates your recommendations regarding allocation of the revenue increase and residential rate design?

A: Yes. Exhibit JFW-2 provides an illustrative design for the Residential ("R") rate class, based on the Company's requested rate of return and revenue increase.[1] The first page of Exhibit JFW-2 shows the allocation of the revenue increase to the residential class that brings the residential rate of return up to requested levels.[2] As indicated on this first page, this allocation results in a 10.3% increase in residential revenues.

The second page of Exhibit JFW-2 illustrates a rate design for the R class that: (1) increases the customer charge by 10.3%, commensurate with the

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[1]This exhibit was developed by modifying electronic-spreadsheet versions of Exhibit JFJ-1, which were provided in response to OPC Data Request No. 5, Question No. 15.

[2]For simplicity, this illustrative calculation assumes that all non-residential distribution rate classes are also brought up to the requested rate of return and eliminates the proposed reduction to the General Service Transmission rate. However, the requested revenue increase could be distributed among the non-residential classes in other ways without affecting the allocation to the residential class.

residential revenue increase; (2) increases the winter initial-block energy rate by 10.3% (relative to the current base rate, excluding the BSA surcharge); and (3) recovers the remaining revenue increase with proportional increases to the summer energy rate and the winter tail-block energy rate. The changes to the energy rates increase the differential between summer and average winter rates and narrow the gap between the initial and tail blocks in the winter.

II. Cost Allocation

Q: What is the purpose of the cost-allocation process?

A: The cost-allocation process assigns the Company's total Maryland-jurisdictional revenue requirement to the various customer and rate classes. The process is generally driven by some concept of fairness. It is a generally accepted principle that allocation based on cost causation results in an equitable sharing of costs.

Q: What are the results of Delmarva's Cost of Service Study?

A: The COSS indicates that for the twelve months ending December 31, 2008, the residential class was paying 105% of the Company's average rate of return.[3]

Q: On which portions of the cost-allocation process do you have comments?

A: I have comments on the allocation of the proposed revenue increase (which is based in part on the Cost of Service Study), and on two aspects of the COSS itself. I will discuss each of these in turn.

[3] *Direct Testimony of Joseph F. Janocha*, Case No. 9192, May 6, 2009, Schedule JFJ-1, page 1.

A. *Allocation of the Revenue Increase*

Q: How does the Company propose to use its Customer Class Cost of Service Study to allocate its requested rate increase among rate classes?

A: The Company relies on the COSS, specifically the allocation of test-year system costs and revenues to individual rate classes, to determine the rate of return achieved by each rate class for the test year. These results, in turn, are relied on to allocate the requested system revenue increase to individual rate classes in order to reduce the difference between the achieved rate of return for each class and the requested rate of return for the Company as a whole.

According to Mr. Janocha, the Company proposes to allocate the revenue increase to all classes other than Telecommunications Network Service such that the difference between the current and the requested rate of return is reduced by 70%. For the TN class, the Company proposes to eliminate the difference between the current and requested rate of return. Under the Company's proposal, revenues from the residential class would increase by 10.8% (compared to a system average increase of 12.4%.)[4] Although residential revenues would increase by a smaller percentage than total revenues, the residential class would continue to pay in excess of the Company's average rate of return. In other words, the Company proposes to allocate to residential customers more of the requested revenue increase than necessary to achieve the requested rate of return.

[4] Janocha Direct, Schedule JFJ-1, page 1.

Q: Would average rates for the residential class also increase by 10.8% under the Company's proposal?

A: No. Average base rates for the residential class would increase by about 18% under the Company's proposal.

The revenue and the base-rate increases are different in this case due to the dramatic decline in retail sales between the 2006 and 2008 test year and the offsetting impact of the Bill Stabilization Adjustment ("BSA") mechanism. Current residential rates were designed to recover the revenue amount approved in Case No. 9093, using billing determinants for the 2006 test year. Since 2006, although actual sales have dropped far below 2006 test-year levels, the BSA mechanism has ensured that the Company continues to recover revenues equivalent to the approved amount. The 10.8% revenue increase requested by the Company represents the increase over the revenue amount approved in Case No. 9093 required to recover the Company's assessment in this proceeding of 2008 test-year revenue requirements (as allocated to the residential class.) In other words, the 10.8% revenue increase represents the increase in residential revenue requirements from the 2006 test year to the Company's estimate for the 2008 test year.

Not only have costs increased by 10.8% from 2006 to 2008, by the Company's estimate, but the retail sales that generate revenues to cover these costs have declined between 2006 and 2008. Revenues for the 2008 test year (the product of 2008 test-year billing determinants and current base rates) are less than the amount approved in Case No. 9093 (the product of 2006 test-year billing determinants and current base rates), because 2008 test-year billing determinants are substantially lower than 2006 test-year levels. The Company is therefore requesting an 18% increase in current base rates in order to bring the residential rate up to a level that, when applied to 2008 test-year billing determinants, generates revenues sufficient to recover both the 10.8% increase in allocated revenue requirements *and* the loss of revenues (relative to the amount approved in Case No. 9093) associated with the decline in retail sales between the 2006 and 2008 test years. The Company has been recovering these sales-related revenue losses through an energy surcharge pursuant to the BSA. The 18% increase thus effectively folds the BSA surcharge recovery of the sales-related deficiency into base rates.

Q: Do you recommend any changes to the Company's proposal for allocating its overall revenue request to the residential class?

A: Yes. Residential revenues should be increased only by that amount necessary to achieve the rate of return authorized by the Commission in this proceeding. The Company has not adequately supported its proposed allocation of the overall revenue increase, specifically its proposal to over-allocate the revenue increase to residential customers. During these dire economic times, it is unreasonable to expect consumers to subsidize other customer classes by bearing more than their fair share of the revenue increase.

Furthermore, as discussed below, the Cost of Service Study relied on as the basis for allocating the revenue increase may overstate the residential class's share of costs. If that is the case, then the extent to which the residential class is under-earning relative to the requested rate of return, and the increase necessary to bring the residential class to the requested rate of return, would be less than indicated by the Company's COSS. In other words, consumers may still be paying more than their equitable share, even if the residential class is allocated the share of the revenue increase indicated by the Company's Cost of Service Study as required to achieve the authorized rate of return.

I therefore recommend that the residential class be allocated only as much of the overall revenue increase approved by the Commission in this proceeding as is necessary to achieve the approved rate of return. In addition, I recommend that the Commission direct the Company to address the problems in its Customer Class Cost of Service Study identified in the following section of my testimony.

B. Delmarva's Cost of Service Study

Q: How does Delmarva allocate distribution plant?

A: According to Mr. Tanos, the COSS allocates distribution plant as follows:

- Primary distribution is assigned on the basis of the class maximum diversified demand ("Class MDD"), that is, the maximum hourly load for the class as a whole.
- Services are allocated on the sum across customers in a class of maximum customer demands ("Customer NCP"), i.e., the sum of each customer's individual maximum hourly demand, regardless of which hour of the year each customer's maximum demand occurs.[5]
- Line transformers are assigned to small secondary customers based on a simple average of Class MDD and Customer NCP, but to large secondary customers based on Customer NCP. Use of this allocator recognizes that

[5]Customer NCP will almost always exceed Class MDD because of load diversity, i.e., the fact that some customers in a class will reach maximum demand at different times than other customers. Customer NCP simply sums the individual maximum demands across all customers in the class, regardless of which hour the individual maximum demand occurs. In contrast, Class MDD is the load in the one hour when the sum of individual customer hourly demands is at its maximum.

small customers share transformers while each large customer requires its own transformer or set of transformers.

- Secondary lines (overhead and underground) are assigned to small secondary customers based on a simple average of Class MDD and Customer NCP. Large general-service secondary customers are not assigned any secondary lines, assuming that all large customers are directly served from the transformer.

Q: Do these allocators reasonably reflect cost causation?

A: These allocators are generally reasonable. However, I have identified two potential issues with the Company's allocation assumptions that may tend to overstate the allocation of costs to the residential class:

- The allocation of line transformers based on a simple average of Class MDD and Customer NCP may understate the diversity of load on these facilities.
- Delmarva's allocation of services based on Customer NCP (which implies zero diversity in customers' loads) does not account for the sharing by several residential customers of a single service line to a multi-family building.

Both of these issues arise from a concern that the Company may be understating residential load diversity in its specification of residential allocators. If load diversity is understated, the COSS will overstate the residential-class contribution to distribution costs and thus over-allocate such costs to the residential class.

Q: How does load diversity affect the sizing of transmission and distribution (“T&D”) plant?

A: The diversity of demand among a group of customers results in a group peak demand that is lower than the sum of customers’ individual maximum demands. In other words, since customers reach their individual peak demands on different days and hours, their loads at the single hour when a distribution facility reaches its peak will be less than the sum of the individual customers’ maximum demands. In general, utilities size T&D plant to meet the group peak, not the sum of customers’ individual maximum demands.

The load diversity on a given piece of distribution equipment depends on the number and type of customers served by that equipment. The farther downstream the distribution equipment, the fewer the customers served, and the lower the load diversity.

Load diversity is frequently reported as a coincidence factor, the ratio of the peak of a group of customers to the sum of their maximum demands. In other words, the coincidence factor measures the percentage of the customers’ maximum demand that occurs at the hour of the group peak.

Q: Do Delmarva’s demand allocators reflect load diversity on distribution plant?

A: Yes. For example, at the primary level, the Company’s analysis assumes a residential load coincidence factor of 33% when it assigns this plant based on the Class MDD factor. In other words, it assumes that the peak of a group of residential customers is 33% of the sum of their maximum annual demands. At the farthest end of the distribution system, at the service drop, Delmarva assumes no diversity of load (or a coincidence factor of 100%) when it allocates this plant according to the sum of individual customers’ maximum demands.

The diversity reflected in Delmarva's demand allocators is shown in the following table of coincidence factors:[6]

Allocator	Total Maryland	Resid	GS @ Secondary	GS @ Primary	Street Light
Class MDD	43%	33%	61%	78%	100%
50/50 MDD–NCP	71%	66%	81%	89%	100%
Customer NCP	100%	100%	100%	100%	100%

Source: Schedule EPT-5, p. 18-2.

Q: Why would under-estimating load diversity overstate the residential class's share of costs?

A: There tends to be more load diversity on the distribution equipment serving small customers, because each piece of equipment typically can serve more small customers than large customers. For example, according to PEPCo's 1985 residential underground distribution guidelines, a 167 kVA transformer can serve 41 residential customers using gas heat and 3½ hp air conditioning, with a total non-coincident demand of 492 kVA.[7] But that same transformer could only serve a single commercial customer with a demand of around 167 kVA. There is no diversity in the large-customer load on the transformer, while the diversity of the residential loads reduces the peak on the transformer by 66% compared to the individual customer peaks. The greater the number of customers on a particular component, the greater the variation in loads and load shapes (that is,

[6] The 50/50 MDD-NCP coincidence factor is calculated as the simple average of the MDD and the NCP coincidence factors.

[7] *Underground Residential Distribution: Loading & Cable Parameters* (DR OPC-RD-1-36, Attachment A provided in Case No. 8466), Tables III and IX.

load diversity), the lower the contribution per customer to the group peak, and the lower the cost per customer.

Q: Has the Company provided any load diversity studies to support its specification of allocators?

A: No. While it recognizes that allocators should reflect load diversity on the distribution facilities, the Company has not conducted a study of load diversity on the Delmarva system.[8]

The Company should undertake such an analysis in order to ensure that its allocators reasonably reflect the impact of load diversity on distribution costs.

1. Line Transformers

Q: What does the Company assume for residential load diversity on line transformers?

A: As noted in the table above, the Company assumes a residential coincidence factor of about 66% when it allocates line-transformer costs using the simple average of Class MDD and Customer NCP.

Q: Has Delmarva provided any analyses to support its use of a 50/50 weighting of Class MDD and Customer NCP, with its implied coincidence factor of 66%?

A: No. Instead, in response to discovery, Mr. Tanos offers a general rationale for using a simple average of Class MDD and Customer NCP:

[8] See the responses to OPC Data Request No. 5, Questions No. 9 and 11. Copies of these and all other responses cited herein are attached.

> Distribution line transformers are allocated using the average of the two demand levels to recognize that transformers may serve multiple customers so that the diversity of load will impact the sizing of the transformer; while other transformers serve a single customer so no load diversity is considered in sizing the transformer.[9]

Lacking any analyses by the Company, I have prepared an illustrative calculation of load diversity on line transformers using the average of Delmarva customers per secondary transformer and PEPCo's estimates of residential load coincidence by number of houses and end use included in its 1985 underground distribution guidelines. This calculation illustrates how the 50/50 weighting may understate diversity on line transformers.

There were 59,097 secondary transformers in Delmarva's Maryland jurisdiction as of year-end 2008, and 201,954 customers for the 2008 test year.[10] Assuming that no secondary transformers are attributable to primary or streetlighting customers, and that secondary general-service customers average one transformer per customer, the remaining transformers would each serve an average of about 5.5 residential customers.

Assuming five residential customers per transformer, PEPCo's 1985 underground distribution guidelines show less than 66% load coincidence for all but the largest electric air-conditioning or heating customers, even when all the customers on the transformer are assumed to have the same-sized air conditioning or heating equipment. Based on Table III of PEPCo's guidelines, as indicated in the following table, a group of five houses each with 2½ hp air conditioning, for example, would have a coincidence factor of 55%:[11]

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[9]Response to OPC Data Request No. 5, Question No. 9.

[10]Response to OPC Data Request No. 9, Question No. 1 and Schedule EPT-5, page 19-1.

[11]The coincidence factors in this and the following table are calculated as the ratio of diversified to undiversifed kVA demand for five houses. Diversifed kVA demand for five houses is

	Air Conditioning (hp)								
	None	*1½*	*2*	*2½*	*3*	*3½*	*4*	*5*	*7½*
1 House	7	9	10	11	11	12	13	15	19
5 Houses diversified kVA	19	22	25	30	33	37	40	48	66
Coincidence Factor	54%	49%	50%	55%	60%	62%	62%	64%	69%

Likewise, as shown in the following table, based on Table IV of PEPCo's guidelines, a group of five houses each with 12.5 kW of electric heating, would have a coincidence factor of 61%:

	Electric Furnace (kW)							
	5	*7.5*	*10*	*12.5*	*15*	*20*	*25*	*30*
1 House	10	15	14	17	18	22	27	31
5 Houses diversified kVA	32	40	44	52	56	80	92	124
Coincidence Factor	64%	53%	63%	61%	62%	73%	68%	80%

If diversity among different types of residential customers were also taken into account, the coincidence factors would be even lower than calculated in these tables. For example, a single transformer may serve some homes with electric heat that peak in the winter, and some with fossil heat that peak in the summer.

2. Sharing of Services

Q: To what extent is load diversity reflected in the Company's allocator for services?

A: The Company uses Customer NCP to allocate services. Because Customer NCP is derived as the sum of individual customers' maximum demand, it reflects zero diversity of customer load.

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provided in the tables. Undiversifed KVa demand is calculated as five times the kVA demand for a single home, as shown in the tables.

Q: Is it reasonable to assume zero diversity of customer load for the allocation of services?

A: No. Such an assumption fails to account for the sharing of services in multi-family buildings. Where services are shared, the load on the equipment is less than the sum of individual customer's maximum demand. In other words, load diversity is greater than zero for these multi-family buildings and, in turn, greater than zero on average for the residential class as a whole.

Q: Have you estimated what the impact of shared services would be on the residential services allocator?

A: I am unable to estimate at this time the impact of shared services, since the Company has not provided data on load diversity required for such a calculation. In addition, Delmarva is unable to provide other necessary information, such as data on the mix of housing types and the number of customers per service in its Maryland jurisdiction.[12]

However, this impact may be significant, since a substantial portion of housing in Delmarva's service territory is multi-family. According to the 2000 Census of Housing, in the counties that Delmarva serves, 18.3% of the customers are in multi-family housing with 2 to 9 units, and 11.4% in multi-family housing with more than 9 units.[13]

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[12]See the responses to OPC Data Request No. 5, Question Nos. 6 and 7.

[13]The Census figures include housing in the Choptank service territory. Since Choptank is likely to serve fewer multi-family dwellings, the percentage of multi-family units in Delmarva's territory is probably understated.

Q: Would similar adjustments apply to other classes?

A: No. Other than multi-family residential customers on the residential rate, relatively few customers are likely to share services.[14]

III. Rate Design

Q: What are your concerns with regard to Delmarva's residential rate design proposals?

A: I have identified two issues with regard to Delmarva's proposed rate design for the residential class. First, the Company's proposal for a 25% increase in the monthly customer charge disproportionately and unreasonably shifts the burden for the revenue increase onto low-usage customers. Second, the Company's proposed method for reducing the declining-block structure in winter rates inappropriately reduces the summer-winter differential in energy charges for large residential customers.

A. Residential Customer Charge

Q: What is Delmarva's proposal with regard to the residential customer charge?

A: The Company proposes to increase the customer charge by 25%. According to Mr. Janocha, this increase will result in a customer charge that recovers 43% of residential revenue requirements identified as customer-related in the COSS.[15]

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[14]In some cases, small commercial customers in a strip mall or office building will share a service.

[15]Janocha Direct, p. 8.

Q: Is the proposed increase reasonable?

A: No. The Company's proposal unreasonably harms small residential customers in the following respects:

- The proposed increase would inappropriately shift recovery of sales-related revenue losses from the volumetric BSA energy surcharge to a fixed customer charge.
- The large increase disproportionately affects small customers' bills. Delmarva's approach would require that the smallest customers (with the least-expensive distribution equipment) pay the average of customer costs attributable to all sizes of residential customers. Using an average cost per customer does not take into account the effect of customer size on cost and results in the subsidy of large customers by small customers within the class.
- The customer charge inappropriately includes costs that the COSS classifies as customer-related, but allocates as load-related.
- The large increase results in a disruptive change to small customers' bills. The Company itself recognizes the need for gradual changes in the customer charge in order to temper intra-class shifts.[16] However, a 25% increase in the customer charge is not a gradual change for a low-usage customer, where the customer charge may represent 20% of the monthly bill.

[16] Janocha Direct, p. 8.

Q: How would the Company's proposal shift recovery of sales-related revenue losses from the volumetric BSA energy surcharge to a fixed customer charge?

A: As discussed above in Section II.A, if not for the drop in sales from 2006 test-year levels, residential customer and energy charges would need to increase by 10.8% to recover the Company's requested revenue amount. Moreover, the revenue losses associated with this sales decline are currently being recovered through a volumetric energy surcharge under the BSA. Thus, an increase in the customer charge greater than 10.8% effectively shifts recovery of sales-related revenue losses from a volumetric energy surcharge to a fixed customer charge.

Q: Why is it unreasonable to recover sales-related revenue losses through the customer charge?

A: It is unreasonable because it effectively allocates to small customers a larger share of the revenue losses than is their responsibility. The revenue losses recovered through the BSA surcharge were due solely to a decline in energy sales.[17] As such, it is likely that customers contributed to revenue losses in proportion to usage. It is therefore reasonable to allocate such revenue losses on energy, as is the case when such losses are recovered through the BSA energy surcharge. In contrast, recovering revenue losses through a fixed customer charge effectively allocates a fixed amount of revenue losses per customer, regardless of customer usage. As a result, smaller customers are allocated the same share of revenue losses as larger customers, even though smaller customers were likely responsible for a smaller share of such costs.

[17] In fact, customer count increased from 2006 to 2008, resulting in revenue growth from the customer charge.

Q: Which costs typically classified as customer-related in cost of service studies should not be included in the calculation of the customer charge?

A: A number of customer-classified costs vary with the size of the customer (in revenues, sales, or demand), and therefore, should be recovered in part through the commodity charge. For example, the service drop for the average small residential customer is likely to be smaller than for the average large customer. Large residential customers are likely to be single-family homes, each using a fairly long service drop. Small customers are more likely to share services in multi-family housing or townhouses, or perhaps in row houses with individual, but short, service lines. Other costs that are classified as customer-related will also vary with the customer's use. For example, uncollectible accounts and collection expense are likely to be larger for large customers than for small customers, since the large customers have larger bills to become uncollectible.

Q: What costs does the COSS classify as customer-related, but allocate on load?

A: The Cost of Service Study allocates service drops on Customer NCP, recognizing that the cost of services varies with customer loads. The Company also allocates half of Customer Service and Sales expenses to customer class based on class energy sales. Yet, Delmarva includes all of these costs in its estimate of customer costs for rate-design purposes. Services, and associated costs, and half of Customer Service and Sales expenses constitute a significant portion of the plant cost that Delmarva includes in the customer charge.

Q: What do you recommend with regard to setting of the residential customer charge?

A: The Company's proposal to increase the customer charge by 25% should be denied. Instead, the Commission should direct the Company to increase the customer charge for the residential rate classes in proportion to the overall revenue increase allocated to those classes.

B. Winter Block Rate

Q: What is the Company's proposal with regard to the declining block structure in the residential winter energy rate?

A: The Company proposes to reduce the current difference between the initial and tail blocks by lowering the initial-block rate by 10% and commensurately raising the tail-block rate.

Q: Do you support the Company's proposal?

A: I support the concept of reducing, and eventually eliminating, the declining block structure.

However, I do not support the method proposed by the Company for reducing the difference between the initial and tail blocks, because it inappropriately eliminates the difference between the summer rate and the average winter rate for large customers with average usage in excess of the initial block.

Q: Why should the Company's residential rate design maintain a seasonal differential in energy charges?

A: Seasonal rate design is consistent with generally accepted cost-causation principles. Charging more for summer usage and less for winter usage may provide customers with more appropriate price signals than rates that are constant over the year. Shifting revenues onto the summer would increase customers' incentive to control summer loads that determine the need for distribution capacity.

In its *Electricity Utility Cost Allocation Manual* (1992, at 143–144), NARUC treats as non-controversial the concept of allocating distribution (and transmission) costs to seasons and time periods. Generally accepted cost-causation principles call for allocating a larger share of distribution costs to high-load seasons than to low-load seasons, where feasible.

For Delmarva in particular, seasonal differentiation is justified by the timing of peak loads and capacity limitations on the Delmarva distribution system. Most of the large and expensive distribution elements—substations and feeders—experience their peak loads in the summer. The Company's data indicate that 85% of its distribution feeders peak in the summer.[18] A majority of Delmarva's substations also peak in the summer.[19] Since summer rated capacity for feeders and substations is lower than winter capacity, distribution capacity is even more strongly driven by summer loads. Hence, Delmarva's distribution rates should almost certainly be higher in summer than winter.

In fact, the Company acknowledges that a seasonal differential is appropriate:

> A level of seasonal rate differentiation could be supported in distribution energy rates on the basis that the peak loads upon which cost allocations are based occur in the summer in the Delmarva Power & Light Maryland Service Territory. That statement notwithstanding, the Company has not performed any studies or analyses which would support the determination of an appropriate level of seasonal differentiation.[20]

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[18]Response to OPC Data Request No. 5, Question No. 25.

[19]Response to OPC Data Request No. 5, Question No. 26, Attachment.

[20]Response to OPC Data Request No. 5, Question No. 23.

Q: What do you recommend with regard to the Company's proposed approach for reducing the difference between the initial and tail blocks?

A: The Company's proposed method should be modified to allow for both a reduction of the declining-block structure in the winter and an increase in the differential between summer and average winter energy rates. Exhibit JFW-2 illustrates one approach for achieving both of these rate-design objectives.

Q: Does this conclude your testimony?

A: Yes.

Exhibit JFW-1

Qualifications of

JONATHAN F. WALLACH

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SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

“The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

“The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities” (with Paul Chernick), *1996 Summer Study on Energy Efficiency in Buildings* 7(7.47–7.55). Washington: American Council for an Energy-Efficient Economy, 1996.

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2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

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2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

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Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

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Reasonableness and risks of resource-procurement plan.

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Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed reliability-pricing model on capacity costs.

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Transition to market-based residential rates. Price volatility, bill complexity, and cost-deferral mechanisms.

Maryland PSC Case No. 9056, default service for commercial and industrial customers; Maryland Office of People's Counsel, April 2006.

Assessment of proposals to modify default service for commercial and industrial customers.

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Assessment of effects and risks of proposed merger on ratepayers.

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Transition to market-based rates. Securitization of power costs. Rate of return on deferred assets.

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Procurement of standard-offer power. Structure and format of bidding. Risk and cost recovery.

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Distorting effects of proposed reliability-pricing model on clearing prices. Economically efficient alternative treatment.

Maryland PSC Case No. 9063, optimal structure of electric industry; Maryland Office of People's Counsel, Direct Testimony, October 2006; Rebuttal November 2006; surrebuttal November 2006.

Procurement of standard-offer power. Risk and gas-price volatility, and their effect on prices and market performance. Alternative procurement strategies.

Maryland PSC Case No. 9073, stranded costs from electric-industry restructuring; Maryland Office of People's Counsel, Direct Testimony, December 2006.

Review of estimates of stranded costs for Baltimore Gas & Electric.

2007 **Maryland PSC** Case No. 9091, rates and rate mechanisms for the Potomac Edison Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9092, rates and rate mechanisms for the Potomac Electric Power Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9093, rates and rate mechanisms for Delmarva Power & Light; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9099, rates and rate mechanisms for Baltimore Gas & Electric; Maryland Office of People's Counsel, Direct, March 2007; Surrebuttal April 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Connecticut DPUC Docket No. 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts.

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Benefits of long-term planning and procurement. Proposed aggregation of customers.

Maryland PSC Case No. 9117, Phase II, residential and small-commercial standard-offer service; Maryland Office of People's Counsel. Direct, October 2007.

Energy efficiency as part of standard-offer-service planning and procurement. Procurement of generation or long-term contracts to meet reliability needs.

2008 **Connecticut DPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Paul Chernick), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

Ontario EB-2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Paul Chernick and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

Delmarva Power & Light Company - Maryland
Development of Proposed Distribution Rate
Rate Class Allocation of Distribution Revenue Requirements

TABLE 1 **Allocation of Operating Income Based on Per Books Cost of Service Study Results**

		TOTAL MARYLAND RETAIL	RESIDENTIAL	GENERAL SERV SECONDARY SMALL	CABLE SERVICE	GENERAL SERV SECONDARY LARGE	GENERAL SERV PRIMARY SMALL	STREET LIGHTING SERVICE
1	Cost of Service Study Results (Schedule EPT-3)							
2	Distribution Revenue							
3	Distribution, Franchise Tax and USP	$ 119,267,408	$ 76,881,603	$ 28,017,024	$ 173,921	$ 5,278,532	$ 5,667,121	$ 3,249,208
4	Other Revenue	$ 1,559,597	$ 1,109,684	$ 276,149	$ 545	$ 74,528	$ 60,241	$ 38,449
5	Total	$ 120,827,004	$ 77,991,287	$ 28,293,173	$ 174,466	$ 5,353,059	$ 5,727,362	$ 3,287,657
6	Operating Income	$ 22,455,581	$ 14,569,006	$ 6,111,600	$ 14,526	$ 785,465	$ 501,889	$ 473,095
7	Distribution Rate Base	$ 286,643,710	$ 176,756,632	$ 64,594,164	$ 200,491	$ 18,588,978	$ 16,471,488	$ 10,031,956
8	ROR	7.83%	8.24%	9.46%	7.25%	4.23%	3.05%	4.72%
9	Unitized ROR	1.00	1.05	1.21	0.92	0.54	0.39	0.60
10	Revenue Requirements Results (Schedule WMV-2)							
11	Operating Income	$ 18,373,864	$ 11,920,820	$ 5,000,704	$ 11,886	$ 642,692	$ 410,661	$ 387,101
12	Distribution Rate Base	$ 310,364,908	$ 191,384,126	$ 69,939,654	$ 217,082	$ 20,127,309	$ 17,834,586	$ 10,862,151
13	ROR	5.92%	6.23%	7.15%	5.48%	3.19%	2.30%	3.56%
14	Unitized ROR	1.00	1.05	1.21	0.92	0.54	0.39	0.60

TABLE 2 **Cost of Service Class Revenue Increase Allocation**

		TOTAL MARYLAND RETAIL	RESIDENTIAL	GENERAL SERV SECONDARY SMALL	CABLE SERVICE	GENERAL SERV SECONDARY LARGE	GENERAL SERV PRIMARY SMALL	STREET LIGHTING SERVICE	GENERAL SERV TRANSMISSION
15	Revenue Requirement (Schedule WMV-2)	14,145,175							
16	Operating Income Deficiency (Schedule WMV-2)	8,255,445							
17	ROR (Schedule WMV-2)	8.58%							
	Proposed Revenue Allocation								
18	UROR Adjustment Factor		1.00	1.00	1.00	1.00	1.00	1.00	
19	UROR		1.00	1.00	1.00	1.00	1.00	1.00	
20	ROR	8.58%	8.58%	8.58%	8.58%	8.58%	8.58%	8.58%	
21	Incremental Income	$ 8,255,445	$ 4,499,938	$ 1,000,119	$ 6,740	$ 1,084,231	$ 1,119,546	$ 544,872	
22	Revenue Conversion Factor	1.7134	1.7134	1.7134	1.7134	1.7134	1.7134	1.7134	
23	Revenue Requirement	$ 14,145,175	$ 7,710,355	$ 1,713,639	$ 11,548	$ 1,857,760	$ 1,918,270	$ 933,602	$ -
24	Final Unitized ROR	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
			-0.05	-0.21	0.08	0.46	0.61	0.40	

TABLE 3 **Rate Schedule Specific Revenue Increase Allocation**

25	Cost of Service Classification		RESIDENTIAL		GENERAL SERV SECONDARY SMALL			CABLE SERVICE
26	Rate Schedule	Total	R	RTOU-ND	SGS-S	GS-SH	GS-WH	TN
27	Annualized Current Distribution Revenue (Schedule JFJ-7)	$ 114,370,358	$ 75,148,657	$ 44,443	$ 24,717,019	$ 1,122,322	$ 2,084	$ 173,897
28	Revenue Change ($)	$ 14,145,175	$ 7,705,798	$ 4,557	$ 1,639,075	$ 74,425	$ 138	$ 11,548
29	Proposed Revenue	$ 128,515,533	$ 82,854,454	$ 49,001	$ 26,356,094	$ 1,196,748	$ 2,223	$ 185,445
30	Revenue Change based on Annualized Current Revenue (%)	12.4%	10.3%	10.3%	6.6%	6.6%	6.6%	6.6%

31	Cost of Service Classification				STREET LIGHTING SERVICE	
32	Rate Schedule	LGS-S	GS-P	GS-T	OL	ORL
33	Annualized Current Distribution Revenue (Schedule JFJ-7)	$ 4,848,072	$ 5,076,873	$ 3,743	$3,165,918	$ 67,330
34	Revenue Change ($)	$ 1,857,760	$ 1,918,270	$ -	$ 914,161	$ 19,441
35	Proposed Revenue	$ 6,705,832	$ 6,995,144	$ 3,743	$ 4,080,079	$ 86,771
36	Revenue Change based on Annualized Current Revenue (%)	38.3%	37.8%	0.0%	28.9%	28.9%

Delmarva Power & Light Company - Maryland
Development of Service Classification Distribution Rates
Using Twelve Months Ending December 2008 Data

Service Classification Residential ("R")

1	Distribution Functional Revenue Requirements Total	$ 82,854,454
2	Proposed Customer Charge Recovery	$ 13,677,348
3	Proposed Demand/Energy Charge Recovery	$ 69,177,106

4	**Delivery Service**	**Billing Determinants**	**Current Distribution Rate**	**Effective Annualized BSA Rate (See Note 1)**	**Present Revenue**	**Preliminary Rate**	**Winter First Block Adjustment Factor 0%**	**Proposed Rate**	**Proposed Revenue**	**Revenue Change**	**Base Rate Change %**
5	Monthly Customer Charge	2,067,550	$ 6.00		$ 12,405,300	$ 6.62	$ -	$ 6.62	$ 13,677,348	$ 1,272,048	10.25%
6	Distribution										
7	Summer Energy Rate	719,478,722	$ 0.027741	$ 0.002198	$ 21,540,228	$ 0.035121	$ -	$ 0.035121	$ 25,268,812	$ 3,728,584	26.60%
8	Winter First Block Energy Rate	924,749,333	$ 0.031293	$ 0.002198	$ 30,970,465	$ 0.034501	$ -	$ 0.034501	$ 31,904,344	$ 933,880	10.25%
9	Winter Second Block Energy Rate	456,740,761	$ 0.020206	$ 0.002198	$ 10,232,664	$ 0.026282		$ 0.026282	$ 12,004,061	$ 1,771,396	30.07%
10	Total Delivery Service	2,100,968,816	$ 0.033571		$ 75,148,657			$ 0.039436	$ 82,854,566	$ 7,705,909	17.47%
11	Rounding Difference								$ 111		

Note 1 The "Effective Annualized BSA Rate" is determined by dividing the difference between allowed test year revenue and the revenue calculated using current rates and billing determinants divided by the service classification appropriate billing determinant for BSA Development.

Attachment 1

1. Response to OPC Data Request No. 5, Question No. 9.
2. Response to OPC Data Request No. 5, Question No. 11.
3. Response to OPC Data Request No. 9, Question No. 1.
4. Response to OPC Data Request No. 5, Question No. 6.
5. Response to OPC Data Request No. 5, Question No. 7.
6. Response to OPC Data Request No. 5, Question No. 25.
7. Response to OPC Data Request No. 5, Question No. 26.
8. Response to OPC Data Request No. 5, Question No. 23.

QUESTION NO. :9

Q. PLEASE PROVIDE THE BASIS FOR THE 50/50 WEIGHTING OF CLASS NCP AND CUSTOMER MAXIMUM DEMANDS USED IN THE ALLOCATION OF (1) LINE TRANSFORMERS, AND (2) SECONDARY PLANT COSTS. PLEASE PROVIDE ALL ANALYSES, STUDIES OF LOAD DIVERSITY, WORKPAPERS, OR ELECTRONIC SPREADSHEETS RELIED ON TO SUPPORT ADOPTION OF THE 50/50 WEIGHTING FOR THESE ALLOCATORS.

RESPONSE:

A. The 50/50 weighting of the class maximum diversified demand and the undiversified sum of the customer maximum demands to allocate distribution line transformers and secondary conductors is consistent with the method approved in Case No. 9093, and represents a reasonable and equitable approach to allocating these plant investments.

Distribution line transformers are allocated using the average of the two demand levels to recognize that transformers may serve multiple customers so that the diversity of load will impact the sizing of the transformer; while other transformers serve a single customer so no load diversity is considered in sizing the transformer. For example, the cost of service study recognizes this latter point by allocating transformers to the large secondary customers based on the sum of the customer maximum demands only.

Secondary conductors originate at the low-voltage side of the distribution transformer and can extend to a customer's service connection to the network from a service drop. Like line transformers, these conductor segments will deliver diversified loads to various customers served off a single conductor and should reflect a consistent allocation approach.

SPONSOR: Elliott P. Tanos

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9192
RESPONSE TO OPC DATA REQUEST NO. 5

QUESTION NO. :11

Q. PLEASE PROVIDE THE COMPANY'S STUDY OF LOAD DIVERSITY ON SECONDARY DISTRIBUTION LINES AND LINE TRANSFORMERS.

RESPONSE:

A. Please refer to the response to Staff Data Request No. 6, Question No.13 for the Company's demand analysis. There is no separate study of load diversity available.

SPONSOR: Elliott P. Tanos

QUESTION NO. :1

Q. PLEASE PROVIDE THE NUMBER OF SECONDARY TRANSFORMERS IN THE MARYLAND JURISDICTION IN THE 12-MONTH PERIOD ENDING DECEMBER 31, 2008.

RESPONSE:

A. 59,097.

SPONSOR: Elliott Tanos

QUESTION NO. :6

Q. PLEASE PROVIDE AN ESTIMATE OF THE PERCENTAGE OF RESIDENTIAL CUSTOMERS THAT LIVE IN MULTIFAMILY DWELLINGS.

RESPONSE:

A. The Company does not keep track of the requested information

SPONSOR: Elliott P. Tanos

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9192
RESPONSE TO OPC DATA REQUEST NO. 5

QUESTION NO. :7

Q. FOR THE RESIDENTIAL RATE CLASS, PLEASE PROVIDE THE AVERAGE NUMBER OF CUSTOMERS PER SERVICE.

RESPONSE:

A. Please refer to the Company's Cost of Service Study, Schedule EPT-5, page 19-1 for the Average Number of Residential Customers. The number of services is not maintained by the Company. Please refer to the response to OPC Data Request No. 5-8.

SPONSOR: Elliott P. Tanos

QUESTION NO. :25

Q. PLEASE SPECIFY THE PERCENTAGE OF FEEDERS THAT PEAK IN THE SUMMER AND THE PERCENTAGE THAT PEAK IN THE WINTER.

RESPONSE:

A. The percentage of feeders that peak in the summer is approximately 85%. The percentage of feeders that peak in the winter is approximately 15%.

SPONSOR: William M. Gausman

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9192
RESPONSE TO OPC DATA REQUEST NO. 5

QUESTION NO. :26

Q. PLEASE PROVIDE THE SUMMER AND WINTER PEAKS ON DELMARVA'S SUBSTATIONS.

RESPONSE:

A. Please refer to the attached listing of summer and winter peaks on the Company's Maryland substations.

SPONSOR: William M. Gausman

DPL MARYLAND SUBSTATIONS	Summer Peak	Winter Peak
138TH STREET	51.8	49.1
ANDORA	2.6	N/A
APPLETON	3.6	N/A
BOHEMIA	2.0	N/A
BOZMAN	12.4	11.5
CALVERT	1.8	N/A
CAMBRIDGE	27.4	22.8
CATHERS	3.4	N/A
CAYOTS	2.5	N/A
CECIL FOUR KV	3.2	N/A
CECIL	112.4	99.5
CENTREVILLE	18.3	20.9
CHARLES	3.2	N/A
CHESAPEAKE CITY	1.6	N/A
CHESAPEAKE	15.2	N/A
CHES-PLY	1.9	1.9
CHESTERTOWN	35.0	32.5
CHURCH HILL	0.0	1.4
CHURCH	14.8	15.1
COLORA	101.5	93.8
COWLANE	0.8	N/A
CRISFIELD 12 kV	13.0	10.0
CRISFIELD 25 kV	3.6	3.2
CULVER	21.0	N/A
DARLINGTON	1.3	N/A
DUBLIN	2.5	N/A
EAST NEW MKT	5.2	4.5
EASTON	5.5	4.1
ELKNECK	0.4	N/A
ELKTON	7.8	N/A
FOUNDRY	1.7	N/A
FRUITLAND	45.5	46.5
GALLION	2.5	N/A
GILPIN	2.1	N/A
GLEN	1.7	N/A
GRACE STREET	16.5	20.7
GRASONVILLE	28.8	38.2
GREENBANK	1.2	N/A
HANCES	1.5	N/A
HARFORD	3.2	N/A
HARRIS	0.8	N/A
HEBRON	4.8	N/A
HILLSBORO	22.4	24.2
HUDSON	1.0	N/A
IRISHTOWN	1.4	N/A
JACKTOWN	8.1	N/A
KENNEY	10.4	N/A
KILBY	0.5	N/A
KINGS CREEK	30.9	N/A
LESLIE	2.1	N/A
LIBERTY GROVE	2.8	N/A
LYNCH	10.1	9.7
MACTON	3.8	N/A
MARIDEL	29.0	21.0
MASSEY	6.9	6.4
MCCLEANS	2.8	2.4

DPL MARYLAND SUBSTATIONS	Summer Peak	Winter Peak
MECHANICS	2.6	N/A
MIDDLE	2.8	N/A
MT. HERMON	72.8	76.9
N. CHESTERTOWN	3.4	2.4
N. SALISBURY	53.1	49.5
NESBITT	2.8	N/A
NORMIRA	2.3	N/A
NORTH EAST	2.3	N/A
OCEAN CITY	26.5	18.3
OCEAN BAY	42.1	37.4
OTSEGO	1.3	N/A
PEMBERTON	28.6	28.5
PERCH	1.7	N/A
PERRYVILLE	2.3	N/A
POCOMOKE	18.8	16.9
PORTERS BRIDGE	1.4	N/A
PRESTON	5.2	4.6
PRICE	9.5	9.7
PRINCE	1.0	N/A
RAILROAD	2.3	N/A
RISING SUN	4.4	N/A
RIVERSIDE	0.4	N/A
ROCK HALL	1.4	0.6
SHARPTOWN	6.1	N/A
STEELE	27.7	27.4
STEVENSVILLE	39.2	55.0
STOCKTON	2.5	N/A
SUSQUEHANNA	25.0	25.4
THEODORE	3.6	N/A
TODD 12kV	4.3	4.2
TODD 25kV	20.3	20.8
TRAPPE	18.5	19.7
TRIUMPH	1.7	N/A
VIENNA	1.0	N/A
WALNUT	1.8	N/A
WAVERLY	0.5	N/A
WEST CAMBRIDGE	20.2	21.2
WHITEFORD	1.4	N/A
WOODLAWN	1.5	N/A
WORCESTER	31.2	24.7
WYE MILLS	14.6	17.7

NOTES:

The data provided represents the current base peak load of each facility and is the result of an analysis of three recent peak periods to account for abnormal operating conditions due to unplanned outages, load transfers, weather, etc. "N/A" indicates that winter peak data is not currently available for the noted substation.

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9192
RESPONSE TO OPC DATA REQUEST NO. 5

QUESTION NO. :23

Q. PLEASE INDICATE WHETHER THE COMPANY BELIEVES THAT SEASONAL DIFFERENTIATION OF ENERGY CHARGES SHOULD BE RETAINED IN RESIDENTIAL RATE DESIGN. PROVIDE THE BASIS FOR THIS RESPONSE, INCLUDING SUPPORTING STUDIES. IF SO, PROVIDE THE COMPANY'S BEST ESTIMATE OF THE APPROPRIATE DIFFERENTIAL AND PROVIDE THE BASIS OF THIS ESTIMATE, INCLUDING ALL SUPPORTING STUDIES AND WORKPAPERS.

RESPONSE:

A. A level of seasonal rate differentiation could be supported in distribution energy rates on the basis that the peak loads upon which cost allocations are based occur in the summer in the Delmarva Power & Light Maryland Service Territory. That statement notwithstanding, the Company has not performed any studies or analyses which would support the determination of an appropriate level of seasonal differentiation.

SPONSOR: Joseph F. Janocha